STATE OF CALIFORNIA

EDMUND G. BROWN JR.

PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN APPLICATION 16-09-003:

This is the proposed decision of Administrative Law Judge Roscow. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's June 21, 2018 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ ANNE E. SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:ek4

Attachment

Decision **PROPOSED DECISION OF ALJ ROSCOW** (Mailed 5/22/2018)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its 2016 Rate Design Window Proposals.	Application 16-09-003

DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY'S 2016 RATE DESIGN WINDOW APPLICATION

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DECISION ON SOUTHERN CALIFORNIA EDISON COMPANY'S 2016 RATE DESIGN WINDOW APPLICATION

Summary

This decision addresses the application of Southern California Edison Company (SCE) for approval of its 2016 Rate Design Window proposals to revise its standard time-of-use (TOU) periods and seasons, implement Critical Peak Pricing (CPP) for certain customers, and revise its real-time-pricing (RTP) rate. The Commission makes the following determinations:

- SCE's current definitions of two seasons are retained: summer (June through September) and winter (October through May);
- New base TOU periods are established to reflect the changing energy market:
    - An on-peak period of 4:00 p.m. to 9:00 p.m. for summer weekdays;
    - A mid-peak period of 4:00 p.m. to 9:00 p.m. for summer weekends and for winter weekdays and weekends;
    - A super off-peak period from 8:00 a.m. to 4:00 p.m. for winter weekdays and weekends; and
    - An off-peak period in the summer and winter for all other hours.
- Directs SCE and the renewable energy water districts that are parties in this proceeding to work collaboratively in SCE's currently-open General Rate Case Phase 2 proceeding to develop an indifference mechanism that, by mutual agreement, will have the result that SCE's Renewable Energy Self-Service Bill Credit Transfer program continues to be a viable mechanism for the governmental entities that participate in the program;
- Approves SCE's proposed changes to its Critical Peak Pricing (CPP) rates;

- Denies without prejudice SCE's alternative proposal to offer CPP as an optional rather than a default rate to customers on its TOU-GS-1 and TOU-PA-3 rate schedules;
- Approves SCE's proposed changes to its Real-Time Pricing tariffs;
- Approves SCE's proposed plan for Marketing, Education, and Outreach; and
- Leaves in place the current 400 MW cap on Option R enrollment.

Any rate or tariff modifications required to implement this decision shall take effect on February 1, 2019.

This proceeding is closed.

1. Background

On September 1, 2016, Southern California Edison Company (SCE) filed Application (A.) 16-09-003, its *Application of Southern California Edison Company for Approval of its 2016 Rate Design Window Proposals* (Application). Pursuant to the Commission's modified Rate Case Plan, SCE and other investor-owned utilities (IOUs) may request rate design changes in years other than those covered by the rate design phase of their General Rate Cases (GRCs), via what is termed a Rate Design Window (RDW) application. The instant application falls between SCE's most recently-concluded GRC Phase 2 proceeding (Application (A.) 14-06-015, Decision (D.) 16-03-030) and its most recently filed, still-pending Phase 2 application (A.17-06-030).

1.1. Time-of-use Policymaking at the Commission

In 2015 the Commission opened Rulemaking (R.) 15-12-012 in order to consider a framework for designing, implementing, and modifying the hourly time periods underlying the time-of-use (TOU) rates that are the basis for electricity charges of many customers in California.[1] The Commission opened the rulemaking to aid its determination of whether peak usage periods or periods during which electricity costs are especially high or especially low may be shifting to later in the day. The Commission noted that properly defined TOU periods will provide incentives for customer use and development of future generation that better reflect the needs of the state's electric grid. This, in turn, should assist in reaching state energy goals by minimizing costs, reducing greenhouse gas emissions (GHG), encouraging conservation, and increasing the supply of electricity at times that best serve the needs of the grid.[2]

The Rulemaking concluded with the Commission's adoption of Decision (D.) 17-01-006, its "Decision Adopting Policy Guidelines to Assess Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments." As the title of D.17-01-006 indicates, the Commission did not adopt specific TOU time intervals or rate design elements; rather, it adopted a framework, including guiding principles, for designing, implementing, and modifying the time intervals reflected in TOU rates. This framework would be applied in subsequent utility-specific rate proceedings in order to determine proper TOU time periods and TOU rate design elements. The guiding principles would act as guidelines for parties in those proceedings to determine TOU time periods during which customers, generators, and providers of energy services should be

[1] Rulemaking 15-12-012, "Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments", filed December 17, 2015.

[2] *Id.* at 2.

encouraged to modify electric usage and supply. The Commission directed that the resulting "base TOU periods" should then be used as the basis for designing TOU rates.

Finally, in D.17-01-006 the Commission noted that new TOU periods should be introduced in a manner that reduces or mitigates negative impacts on customers, such that transition mitigation measures may be necessary for some customers when transitioning to new TOU periods. The Commission allowed certain existing solar customers to retain their current TOU periods for five years (residential) or ten years (non-residential) and directed that the treatment of transitions for other customer groups and for future TOU periods changes should be addressed in IOU-specific rate cases by applying the guiding principles adopted in D.17-01-006.[3]

SCE filed the instant application nearly five months before the Commission adopted D.17-01-006. Thus, while D.17-01-006 is not binding on this proceeding, we are comfortable referencing its guidance as we consider the TOU periods proposed by parties in this proceeding. The principles are attached to this decision as Appendix 1.

1.2. Procedural History

The instant proceeding originates from events that occurred prior to or in parallel with R.15-12-012. In 2014, SCE filed its GRC Phase 2 application to establish marginal costs, allocate revenues, design rates, and implement additional dynamic pricing rates (A.14-06-014). Parties resolved the issues in that proceeding by entering into a number of settlements, which the Commission

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[3] The referenced IOUs, or Investor-Owned Utilities, are SCE, Pacific Gas and Electric Company (PG&E) and San Diego Gas and Electric Company (SDG&E).

approved in D.16-03-030. The adopted "Marginal Cost and Revenue Allocation Settlement Agreement" required SCE to file a RDW application no later than September 1, 2016, to include the following studies and proposals:

- SCE shall investigate and propose (if warranted) new default time-of-use periods;
- The new TOU periods shall not result in modifications to the settled-upon revenue allocations approved by D.16-03-030;
- The new TOU periods shall reflect changes to the load curve net of Renewables Portfolio Standard (RPS) generation capacity output (the "net load curve"); and
- SCE will include a new study of the time dependence, and, at its option, the temperature-dependence, of its marginal subtransmission and distribution costs.

SCE filed the instant application in compliance with these requirements. SCE originally proposed to implement any changes resulting from this proceeding in October, 2018 but in rebuttal testimony, modified its proposal to implement the new TOU periods established in this proceeding for all nonresidential customers on most TOU rate schedules (*i.e.*, rate schedules other than those with a super-off-peak rate) no sooner than February, 2019. This later date would coincide with the likely implementation date for any changes from SCE's GRC Phase 2 application.

On October 7, 2016, protests to SCE's application were filed and served by the Commission's Office of Ratepayer Advocates (ORA), California Solar Energy Industries Association (CALSEIA), Solar Energy Industries Association (SEIA), the City of Lancaster (Lancaster), and the California Farm Bureau Federation (Farm Bureau). SCE replied to the protests on October 17, 2016.

On December 8, 2016, the assigned Administrative Law Judge (ALJ) conducted a prehearing conference in order to determine parties, discuss the scope and schedule of the proceeding, and address other procedural matters. A workshop was held on the same day in order to provide SCE, intervenors, and Commission staff the opportunity to discuss the methodologies supporting SCE's proposed TOU periods.

The assigned Commissioner and ALJ issued the Scoping Memo and Ruling (Scoping Memo) on March 21, 2017. The Scoping Memo defined the issues that would be considered in the proceeding, established a schedule, confirmed the preliminary categorization of the proceeding as ratesetting, and confirmed the need for evidentiary hearings.

Opening testimony was served on April 28, 2017 by ORA, SEIA, CALSEIA, Agricultural Energy Consumers Association (AECA), Farm Bureau, California Large Energy Consumers Association (CLECA), the California Manufacturers & Technology Association (CMTA), Energy Users Forum (EUF), Castaic Lake Water Agency (CLWA), Rancho California Water District (RCWD), Renewable Energy Water Districts (REWD) and Small Business Utility Advocates (SBUA).

As directed by the Scoping Memo, on April 28, 2017 SCE served supplemental testimony that explained how SCE's application addresses certain elements identified within the Commission's "Distributed Energy Resources Action Plan" (DER Action Plan).

SCE, CLECA and CMTA (jointly), EUF, and CALSEIA served rebuttal testimony on June 9, 2017.

On August 7, 2017 SCE filed and served several stipulations:

- SCE-Agricultural Parties Joint Stipulation Resolving Issues in SCE 2016 RDW Proceeding (Exhibit SCE-CFBF-AECA-1)
- SCE-CLWA Joint Stipulation in SCE 2016 RDW Proceeding (Exhibit SCE-CLWA-1)

- SCE-SBUA Joint Stipulation Resolving Issues in SCE 2016 RDW Proceeding (Exhibit SCE-SBUA-1)

Two days of evidentiary hearings took place on August 7 and 9, 2017.

Pursuant to Rule 12.1(b), on August 17, 2017 SCE provided notice to all other parties of its intent to conduct a settlement conference with respect to the Joint Stipulation Resolving Issues between SCE and SBUA. On August 24, 2017 SCE and SBUA filed a Joint Motion for Adoption of Settlement Agreement.

Opening briefs were filed on September 9, 2017 by SCE, ORA, Farm Bureau, SEIA, SBUA, EUF, ORA, CMTA, RCWD, CALSEIA, and CLECA.

Reply briefs were filed on September 29, 2017 by SCE, ORA, SEIA, CMTA, and CLECA, at which time this proceeding was submitted for Commission decision.

2. Issues to be Decided

The Scoping Memo determined that the following issues are within the scope of this proceeding:

1. Whether the Commission should approve SCE's proposal to revise its standard TOU periods and seasons, and implement the revised standard TOU periods for all non-residential customers on rate schedules with standard TOU periods;[4]
2. Whether the Commission should approve SCE's proposal to implement default critical peak pricing (CPP) for more than 500,000 small and medium commercial customers and 1,500 large agricultural customers, or adopt SCE's alternate

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[4] SCE clarifies that rate schedules with "standard" TOU periods are those rate schedules whose TOU periods align with the TOU periods used for marginal cost and revenue allocation studies. SCE further notes that the Commission and other parties at times refer to standard TOU periods as "default" TOU periods. (SCE Application at 6.)

proposal, which would make CPP optional for small commercial customers only;

3. Whether the Commission should approve SCE's proposal to revise its real-time-pricing rate;
4. Whether the Commission should eliminate the cap on enrollment on SCE's Option R tariffs; and
5. Examination of how SCE's application addresses any or all of the vision and continuing elements identified within the Rates and Tariffs group of the DER Action Plan.

3. Base Time-Of-Use Periods

When the Commission opened R.15-12-012, it explained the purpose of the proceeding by noting that TOU pricing is the form of rate design that is most commonly used to communicate to the customer when system costs are high or low, or to create incentives for a customer to shift usage to times that are better for the overall electric system. The Commission further noted that as more customers are enrolled in TOU rate schedules, it is increasingly important that the time periods and corresponding prices defined in TOU rates provide accurate incentives for energy generation, storage, and use at appropriate times throughout each day.

The Commission also stressed the timeliness of the Rulemaking. As the proportion of California's energy generated by renewable resources has increased, solar energy has been offsetting or supplying a larger proportion of demand during the traditional times of peak energy use, weekday afternoons. This increase in intermittent, non-dispatchable energy from renewable sources, combined with the availability of electricity from existing baseload generation from fossil sources, was expected to result in the availability of plentiful electricity during early afternoon hours, where historically demand has been higher and more expensive to serve. As a result, "net load" (total electric demand minus the amounts supplied by solar and wind generation) is now predicted to "ramp up" and increase rapidly in evenings, as demand remains high but solar power is no longer available after sundown. Prices would follow these trends in demand, with lower prices in the afternoon and higher prices in the evening. The emergence of this shift led utilities to consider changes to their TOU time periods to reflect changes in the times when electricity is the most expensive.

Having participated in R.15-12-012, SCE to a large degree anticipated and reflects the guidance from that proceeding in its RDW proposals. SCE offers its own list of principles that underlie its TOU methodology and the resulting revised base TOU periods:[5]

- Utility-specific marginal costs should be the principal basis for the proposed TOU periods.
- While the primary goal of correctly-defined TOU periods is to send accurate price signals that address the challenging system conditions identified in R.15-12-012, the final determination of TOU periods should also consider the principles of customer understanding, acceptance, and ability to respond to the price signals incorporated in the new TOU periods. Such considerations include limiting the number of TOU periods, helping to ensure that TOU periods are not too short, and aligning the starting and ending times for TOU periods across seasons.
- Stability: TOU periods and associated pricing should be predictable and stable over time to minimize unexpected changes to customers' investments and behaviors.

Tables 1-A and 1-B below summarizes SCE's proposed TOU periods:

[5] Exhibit SCE-1 at 50.

Table 1-A

SCE Current and Proposed
TOU Periods (Weekdays)

TOU Period	Summer (June – September)		Winter (October – May)	
	Current	Proposed	Current	Proposed
On-peak	12 p.m. - 6 p.m.	4 p.m. - 9 p.m.		
Mid Peak	8 a.m. - 12 p.m. and 6 p.m. - 11 p.m.		8 a.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	11 p.m. - 8 a.m.	All hours except 4 p.m. - 9 p.m.	9 p.m. - 8 a.m.	9 p.m. - 8 a.m.
Super-off-peak	N/A		N/A	8 a.m. - 4 p.m.

Table 1-B

SCE Current and Proposed
TOU Periods (Weekends)

TOU Period	Summer (June – September)		Winter (October – May)	
	Current	Proposed	Current	Proposed
On-peak				
Mid Peak		4 p.m. - 9 p.m.		4 p.m. - 9 p.m.
Off-peak	All hours	All hours except 4 p.m. - 9 p.m.	All hours	9 p.m. - 8 a.m.
Super-off-peak				8 a.m. - 4 p.m.

As will be seen below, other parties also rely on the guiding principles adopted in D.17-01-006 to support their positions regarding SCE's proposals. Thus, we are comfortable referencing that guidance as we consider the TOU periods proposed by parties in this proceeding.

3.1. Marginal Costs

SCE begins its substantive showing by reviewing marginal cost principles. As noted by SCE, this Commission's reliance on marginal cost principles for revenue allocation and rate design is "long-standing and based on well-founded economic principles."[6] SCE also notes that in D.17-01-006, the Commission found, in pertinent part, that "base TOU periods" should be developed using forward-looking data, with the forecast year set at least three years after the base TOU periods will go into effect. Accordingly, the TOU pricing periods SCE proposes in this proceeding are based on its updated marginal cost analysis of generation energy and capacity costs, as well as an assessment of the time differentiation of certain distribution system costs. SCE developed its marginal cost studies using forecasts of supply-and-demand conditions expected in 2024, which is approximately five years out from SCE's proposed implementation date for the updated TOU periods, February 2019.

Although the Commission's reliance on marginal cost principles is long-established, parties in this proceeding disagreed on some of the numerical inputs to those calculations. These disagreements must be resolved before reviewing parties' proposed TOU periods.

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[6] *Id.* at 12.

3.1.1. The Appropriate Reference Year

Public Utilities Code Section 745(c)(3) directs the Commission to "strive" for residential TOU periods that are appropriate for at least the following five years. While we are not setting residential TOU periods in this proceeding, SCE states that the cost basis for the adopted non-residential TOU periods will be used to inform SCE's January 1, 2018 RDW application addressing the rate design and implementation of default TOU rates for residential customers. Therefore, SCE recommends that forecasts of supply and demand conditions in 2024 serve as the basis for the marginal cost analyses to determine its base TOU periods, which will be in place from early 2019 through at least 2024. SCE asserts that in order to ensure that price signals remain appropriate over this period, its TOU periods should be set "based on expected conditions in the future and should have sufficient duration to provide stability over reasonable planning periods for SCE and its customers."[7] That said, SCE prepared its marginal cost study using data from 2021 as well as 2024 so that parties could analyze both scenarios.[8]

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[7] *Id.* at 15.

[8] SCE also provided useful visual demonstrations of its analyses and resulting proposals by preparing "heat maps" using a methodology first developed by the Commission's Energy Division in R.15-12-012. In that proceeding, parties relied upon marginal cost studies to develop "Target Time Periods" during which it would be helpful to the California power grid for customers to modify their level of energy use. In order to facilitate comparisons between various proposals, the Energy Division provided templates for marginal cost studies that expressed marginal generation energy costs and marginal generation capacity costs in dollars-per-kilowatt-per-hour ($/kWh) summed for each hour in the year. The aggregated results were displayed visually in a "heat map" that averaged the costs in each hour, in each month. The heat maps included in SCE's testimony in this RDW proceeding display a color scheme that reflects the 90th percentile of the average hourly value (load or cost, respectively) in red, the 50th percentile of the average hourly value in yellow, and the 10th percentile of the average hourly value in green.

SCE notes that the concerns about the accuracy of current TOU periods have been caused by the impact on the load profiles of SCE and other utilities due to the statutory increases in California's RPS targets from 20% in 2013 to 33% in 2020; SCE suggests that these impacts will only intensify as California moves to 40% by 2024 and 50% RPS by 2030, and behind-the-meter (BTM) distributed generation (DG) continues to grow. For these reasons, SCE recommends that 2024 is the appropriate reference year because (1) it is the approximate midpoint between the requirements of 33% RPS (in 2020) and 50% RPS (in 2030), and (2) it is five years after the expected 2019 transition of residential customers to default TOU rates.

CLECA, CMTA and EUF also support use of 2024 forecast data as the reference year, while ORA and SEIA recommend use of 2021 forecast data.

ORA notes that SCE's proposed use of 2024 data was over five years ahead of their initially-proposed implementation date of October 2018. ORA suggests that using a reference year so far into the future could increase likelihood of forecasting errors in the development of TOU periods, while the forecasting errors associated with a 2021 forecast would likely be smaller.

SEIA also suggests that SCE's use of a 2024 forecast of its marginal costs as the basis for determining TOU periods interjects an unnecessary level of uncertainty into the forecast.[9] SEIA also cites D.17-01-006 and Guiding Principle number 4, which "directed that TOU periods should be developed using forward-looking data forecasted at least three years after the TOU period will go into effect":

[9] Exhibit SEIA-01 at 8.

> The three-years-in-the-future requirement clearly shows the Commission's intent to have TOU periods best reflect system marginal costs on average during the minimum five-year period during which the TOU periods actually would be in effect.

Parties appear to agree that D.17-01-006 mandates that "base TOU periods" should be developed using forward-looking data, with the forecast year set at least three years after the base TOU periods will go into effect. Since the Base TOU periods adopted in this decision will go into effect in 2019, only forecasts set in 2022 or beyond literally meet this mandate, so we are reluctant to rely on the 2021 forecast, as recommended by ORA and SEIA . Regarding those parties' concerns about reduced accuracy of a later 2024 forecast, we note that SCE stated in its direct testimony that the differences in its marginal cost studies for 2021 and 2024 for the purposes of TOU period determination are not significant.[10] In its rebuttal testimony, SCE provided a more detailed comparison it its 2021 and 2024 cost profiles. SCE prepared "heat map" charts to show graphically that "the hourly cost profiles for years 2021 and 2024 are generally consistent and both align with SCE's proposed TOU periods."[11]

We are reassured by SCE's testimony and demonstration that the differences in the results of its marginal cost studies for 2021 and 2024 with regard to determining TOU periods are not significant. Therefore, SCE's marginal cost study using data from 2024 should be used in the marginal cost analyses for setting SCE's base TOU periods.

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10 *Ibid.*, footnote 30.

11 Exhibit SCE-03 at 42-43, including Figure III-23 and III-24 (showing average hourly costs in 2021 and 2024).

We next turn to parties' proposed marginal generation, distribution and transmission costs.

3.1.2. Marginal Generation Costs

There are two categories of marginal generation costs that capture the cost of serving an additional increment of customer demand: marginal energy costs and marginal generation capacity costs. First, the Commission's methodology relies on a "system market energy price" for estimating the avoided cost of energy. Second, for the marginal generation capacity cost, the Commission's methodology relies on a proxy for estimating the avoided cost of capacity. SCE argues that this remains an appropriate approach in California's current "hybrid" market, where energy procurement is transacted largely through market transactions, and capacity requirements are met through a combination of utility long-term procurement and annual resource adequacy (RA) requirements.

3.1.2.1.Marginal Energy Costs

Marginal energy costs (MECs) reflect the hourly marginal market-clearing price of the California Independent System Operator (CAISO) wholesale power market, and are forecast using production simulation models of market clearing prices. No party contested SCE's results and SCE incorporated its 2024 MECs in its overall cost analysis supporting its proposed TOU periods.

We approve SCE's uncontested 2024 marginal energy costs.

3.1.3. Marginal Generation Capacity Costs

The proper assumption for marginal generation capacity costs (MGCC) is a more controversial matter among parties.

SCE notes that MGCCs have historically reflected the capacity cost of meeting system peak conditions, with the proxy equaling the deferral value of a combustion turbine (CT) generator. However, as intermittent renewable energy resource penetration has expanded throughout California, multiple parties have identified the need to enhance the Commission's RA program, or the system capacity framework, to include physical attributes for "flexible capacity," which is associated with the ramping need created by increased renewables and shrinking demand.

SCE explains that as the electric system evolves and California progresses towards its 50% RPS requirement, the need for flexible capacity will increase and require the utilities to assess the costs directly associated with the procurement of flexible capacity. For this reason, SCE argues that flexible capacity costs should be recognized as a cost driver relevant to TOU period and TOU price determinations, and these costs should be determined by a marginal cost methodology consistent with the framework adopted in the Commission's RA program. Using a methodology that reflects these changes to calculate a CT proxy and using the MECs it also calculated, SCE derived an annual marginal capacity cost of $147.26 per kW-year.[12] SCE's proposal is supported by ORA, CLECA and CMTA.

CLECA explains why it supports what it describes as "SCE's novel approach":

> Given the increasing levels of mandated renewables procurement, with the associated imposition of increasing ramping needs, [SCE's approach] recognizes the growing concern with steep evening ramps, as well as the use of an advanced CT. SCE's efforts to assign some of these marginal generation capacity costs to both the system

[12] *Id*. at 23.

> and flexibility function are a good first step in reflecting the need for flexibility and its extension into the winter months.[13]

SEIA disagree with SCE's approach. SEIA recommends that this proceeding use a MGCC of $86 per kW-year, which is midway between the 2021 going-forward costs of existing capacity ($27.70 per kW-year) and SCE's estimated cost of new CT capacity ($143.94 per kW-year). SEIA states that $86 per kW-year also is consistent with ORA's recommendation of a 40% reduction to SCE's CT-based costs in SCE's last Phase 2 proceeding.

CMTA opposes SEIA's proposal, arguing that, absent a settlement, there are no legal or evidentiary bases for accepting SEIA's recommendation to simply take the midpoint between two values: the Commission can only approve marginal costs that are based on valid and viable legal and evidentiary foundations. CLECA opposes SEIA's proposal for similar reasons.

We agree with parties who argue that, absent a settlement, the Commission should adopt a value for marginal generation capacity costs that is calculated using specific inputs, as SCE has done, rather than considering SEIA's approach of picking a midpoint between an SCE value and a PG&E value. Therefore, we adopt SCE's MGCC of $147.26 per kW-year.

3.1.4. Marginal Distribution Costs

Pursuant to the Commission's adopted methodology, SCE typically separates distribution marginal costs into (1) customer-related components and (2) "design demand" components. SCE explains:

> To maintain service reliability and to meet the demand needs of our customers, SCE expands, upgrades, and reinforces all

[13] CLECA Opening Brief at 6.

> levels of its electric system, including transmission, sub-transmission, and distribution assets. SCE uses peak load data and load growth forecasts to evaluate whether existing distribution facilities will exceed their loading thresholds (also known as a planning load limit) under normal and abnormal conditions, and plans infrastructure projects to mitigate existing and expected constraints.[14]

Based on the above, customer-related costs are designed to collect some "fixed" portion of the utility's distribution costs (*i.e.*, the costs of connecting a new customer to the grid that are not considered to be dependent on the level of demand or usage of the system, plus any marginal costs of providing service to customers). The "design demand" portion of marginal costs are associated with distribution capacity, and are typically considered "peak load-driven" costs.[15]

Pursuant to a term in the Marginal Cost and Revenue Allocation Settlement Agreement adopted in D.16-03-030, SCE agreed to review the time-differentiation of distribution costs in this proceeding. This review was motivated by the fact that California's policy of promoting customer choice in the adoption of customer-sited renewable energy systems (DERs) will require the distribution grid to increasingly serve two different functions:

1) a peak capacity function to meet peak customer demand, which is time-dependent (and should be used to inform the hourly allocation of distribution costs); and

2) a grid or network function that enables the bi-directional transfer of energy to and from customers, which is not time- or peak- dependent.

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[14] Exhibit SCE-1 at 33-34, footnotes omitted.

[15] *Id.* at 33.

In order to more accurately reflect these changes in the drivers of distribution marginal costs, SCE developed a "Peak Load Risk Factor" (PLRF) methodology that further splits design demand distribution marginal costs according to those two functions. SCE proposes that this methodology be used on an interim basis in this proceeding, with the expectation that SCE will include a more comprehensive evaluation of distribution costs in SCE's 2018 GRC Phase 2 proceeding.[16]

CLECA endorses SCE's approach, noting "SCE forecasts DER penetration on the distribution system in 2024, and compares the result to 2014 hourly circuit load; SCE concludes that by [2024] 'the timing of circuit peak demands will shift to later in the day and that peaking may occur on the distribution circuits and substations later in the day'."[17]

SEIA disagrees that SCE's PLRF methodology yields a reasonable allocation of marginal distribution costs, for four reasons. Two of SEIA's objections are based on hypotheticals, namely that SCE should not assume that future DG will be sited in the same location as existing DG, and SCE did not account for the possibility that increasing loads from other types of distributed energy resources (e.g., on-site storage, electric vehicle charging, and load management technologies) might offset the forecast load reductions from DG resources. SEIA's third objection involves technical interpretations of SCE's PLRF methodology versus SEIA's preference for a "peak capacity allocation factor" (PCAF) methodology which weights hours that exceed the distribution

16 *Id.* at 34.

17 CLECA Opening Brief, citing Exhibit SCE-1 at 41.

planning trigger threshold by how much they exceed that threshold. Fourth, SEIA criticizes SCE's use of 2024 PLRFs to analyze 2021 marginal costs.

SCE addressed SEIA's criticisms in rebuttal testimony.[18] SCE offers reasonable counterarguments to SEIA's two hypotheticals, and further explains its PLRF methodology to show that SEIA's criticisms were unfounded. SCE also developed new PLRFs for the year 2021 for its rebuttal testimony and showed that they are generally consistent to its 2024 PLRFs.

We find merit in SCE's approach to implementing the settlement agreement adopted in D.16-03-030, and the resulting methodology for determining distribution marginal costs in this proceeding. SCE responses to SEIA show that it reasonably accounted for future DG penetration, and its methodology and results are also supported by ORA, CLECA and CMTA. We are also reluctant to rely on SEIA's approach, which CLECA showed relies on older data. Therefore, we approve SCE's proposed distribution marginal costs.

3.1.5. Marginal Transmission Costs

Another area of controversy in this proceeding involves the proper role of marginal transmission costs in determining SCE's TOU periods. SEIA asserts that the Commission's guidance in D.17-01-006 included direction that appropriately designed TOU periods must consider the hourly profile of all elements of a utility's marginal costs that vary with customer usage and demand, that is, energy, generation capacity, transmission, and distribution.[19] SEIA argues that SCE's proposed TOU periods are not compliant with this "principal guideline" because they do not consider marginal transmission costs. This

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18 Exhibit SCE-03 at 30-38.

19 D.17-01-006 at. 27; *see also*, *I*d. at 12.

contrasts with SEIA's testimony, which includes the marginal cost of the CAISO-level bulk transmission system, which SEIA defines as the transmission facilities that are regulated by the Federal Energy Regulatory Commission (FERC).

SCE responded to SEIA's criticism by agreeing that it did not include time-differentiation of <u>long-run</u> marginal transmission costs when determining SCE's TOU period proposal, as explained in its testimony.[20] Nevertheless, SCE argues that after some erroneous assumptions used by SEIA are corrected, the inclusion of long-run marginal transmission costs in determining TOU periods does not impact SCE's overall TOU period proposal.[21]

CLECA also devotes a considerable portion of its rebuttal testimony to a critique of SEIA's proposed marginal transmission costs. CLECA acknowledges that the Commission directed that time-differentiated transmission costs adopted by the FERC be considered as part of the cost analysis for determining TOU periods. However, CLECA also notes that for SCE, FERC has not approved time-differentiation of transmission costs or rates (instead, FERC uses an "embedded cost methodology based on a 12- monthly coincident peak" for SCE).

As it has throughout this proceeding, CLECA succinctly places this dispute over methodology into a more understandable context. CLECA explains that the transmission system's basic functions can be described as: (1) meeting reliability needs; (2) meeting policy needs (e.g., enabling renewable resources to serve load); and (3) meeting economic needs (relieving congestion). While a line

[20] Exhibit SCE-1 at 43-44. SCE elaborates on this explanation in its rebuttal, Exhibit SCE-03 at 12-28.

[21] Exhibit SCE-03 at 23-26.

built for one purpose listed above may serve a secondary purpose on the list, determining the relevant proportions "would require a very careful parsing of costs (a very complex undertaking)."[22] More to the point, the determination of marginal costs does not consider "use": it simply reflects an increase in costs associated with an increase in load. CLECA explains that SCE did not propose marginal transmission costs because "the proportion of expected SCE transmission capital expenditures for load growth is fairly minimal when compared to the amount SCE expects to spend to integrate RPS resources."[23]

Based on the above, CLECA faults SEIA's proposal for marginal transmission costs because SEIA failed to do the necessary analysis to separate transmission investment associated with load growth from transmission investment made for other purposes.

We do not find it necessary to incorporate marginal transmission costs into SCE's TOU period calculations at this time. One of the nuances in the guiding principles that we adopted in D.17-01-006 was that "<u>going forward</u>, the IOUs should include information on marginal distribution costs that contribute to peak load costs and time of use information filed or adopted in FERC transmission rate proceedings. Use of marginal distribution and transmission cost information in setting <u>future</u> Base TOU periods will be addressed in individual IOU rate proceedings."[24] In other words, it is premature to insist on incorporating marginal transmission costs in this proceeding, which SCE filed

[22] CLECA Opening Brief at 8, citing testimony at hearing by SCE's witness (Reporter's Transcript [RT] at 81).

[23] *Id.* at 9, citing testimony at hearing by SCE's witness (RT at 79).

[24] *D.17-01-006 at 12, Guideline 2*. Emphasis added.

even before D.17-01-006 was adopted. That decision did direct that transmission cost information should be used in future rate proceedings, and we expect that SCE and other interested parties will place that information before us accordingly.

3.2. Day Type Differentiation (Weekday/Weekend)

SCE proposes to establish summertime TOU periods that would differ between weekdays and weekends. SEIA opposes this differentiation, preferring the simplicity for the customer of having a consistent set of TOU periods on all days of the week. SCE argues that SEIA's proposal is inconsistent with the underlying cost data, because SCE's rebuttal testimony shows that summer weekday and weekend costs vary dramatically.

CLECA does not oppose SCE's proposals, which CLECA describes as "reflective of reality".[25] EUF supports SCE's proposal on the basis of likely customer acceptance because the definitions are simple to understand and easy to remember, which will ease customer planning and behavior changes.

As will be seen below, our adopted TOU periods reflect SCE's proposed differentiation. We agree with SCE that we should be guided by the underlying cost data.

3.3. Seasonal Definitions

SCE proposes to maintain its historical four-month summer season (June-September), asserting that the underlying cost data supports the continuation of SCE's four-month summer definition. SCE also notes that continuity will facilitate customer understanding and acceptance.

[25] CLECA notes that the CAISO Department of Market Monitoring Report for 2015 shows that many of the largest ramps in the year occur on weekends.

SEIA proposes a new six-month summer (May-October). SCE responded by demonstrating that the costs for May and October are more similar to the winter months than to the actual summer months, using both its own data, and using SEIA's data. SCE also observes, with the concurrence of SEIA, that the underlying cost data is more supportive of a shorter summer, not a longer one. SEIA also bases its calculations on long-range forecasts of "the expected impacts of climate change on California." In response, CMTA and CLECA argued that SEIA's reliance on such non-cost-based data does not support the proper determination of TOU season definitions, while also noting that the Commission recognized that "forecast assumptions underlying TOU time periods may deviate over time as more up-to-date data become available," and has already included off-ramps and a "five-year (or every other GRC)" schedule to reevaluate TOU periods.

We agree that SCE's definition of the summer season must be data-based, and we decline to speculate on how rapidly advancing climate change may cause the months of May and October to appear more summer-like than they do today. We also agree with CMTA and CLECA that D.17-01-006 included mechanisms that will allow us to update the forecasts underlying SCE's TOU periods, should future conditions indicate the need to do so.

3.4. Adopted TOU Periods

Based on their respective marginal costs discussed above, three parties presented fully developed TOU periods in this proceeding: SCE, ORA, and SEIA. The remaining parties submitted testimony and briefs in support of one of these three proposals. Parties' proposed TOU periods are summarized in the tables below.

Table 2-A

Proposed TOU Periods (Weekdays)

TOU Period	Summer (June – September)			Winter (October – May)		
	SCE	ORA	SEIA	SCE	ORA	SEIA
On-peak	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	2 p.m. - 8 p.m.			
Mid Peak			noon - 2 p.m.; 8 p.m. - 10 p.m.	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	2 p.m. - 8 p.m.
Off-peak	All other hours	All other hours	All other hours	9 p.m.- 8 a.m.	8 p.m. - 8 a.m.	All other hours
Super-off-peak				8 a.m. - 4 p.m.	8 a.m. – 3 p.m.	

Table 2-B
Proposed TOU Periods (Weekends)

TOU Period	Summer (June – September)			Winter (October – May)		
	SCE	ORA	SEIA	SCE	ORA	SEIA
On-peak			2 p.m. - 8 p.m.			
Mid Peak	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	noon - 2 p.m.; 8 p.m. - 10 p.m.	4 p.m. - 9 p.m.	3 p.m. - 8 p.m.	2 p.m. - 8 p.m.
Off-peak	All other hours	All other hours	All other hours	9 p.m. - 8 a.m.	8 p.m. - 8 a.m.	All other hours
Super-off-peak				8 a.m. - 4 p.m.	8 a.m. – 3 p.m.	

SCE states that its proposal is based on marginal costs, as mandated by the D.17-01-006, is consistent with recent CAISO guidance for peak period hours, and proposes a summer on-peak TOU period identical to that adopted recently by the Commission for SDG&E in D.17-08-030.

ORA states that its marginal cost data supports an on-peak period of 3 p.m. to 8 p.m., which would be a more gradual change from the current on-peak period of 12 p.m. to 6 p.m. than SCE's proposal of 4 p.m. to 9 p.m. ORA also asserts that its proposal more appropriately reflects the policy objectives articulated in R.15-12-012 because it is based on SCE-specific marginal costs, while taking into account customer considerations more so than SCE's proposal.

Finally, ORA notes that its peak-period proposal provides a more gradual change for customers who have faced the same TOU periods for more than 30 years.

SEIA argues that SCE's proposed summer on-peak period of 4:00 p.m. to 9:00 p.m. is not supported by the Commission's recently adopted policies on setting TOU periods and therefore must be rejected. Instead, the Commission should adopt SEIA's more moderate, cost-based change to a summer peak period of 2:00 p.m. to 8:00 p.m. As noted above, SEIA argues that SCE's proposed TOU periods are not compliant with a principal guideline in D.17-01-006 because they do not consider marginal transmission costs, while its proposed summer peak period of 2:00 p.m. to 8:00 p.m. (with a two hour partial peak period on both sides of the peak period) takes into account all four components of utility service: energy, generation capacity, distribution, and transmission. SEIA also asserts that its proposed on-peak period includes all of the hours with the steepest up-ramps in net loads, and weights each of these hours equally. As a result, SEIA's proposed TOU periods better reflect system cost causation, will provide the most accurate price signals to customers, and will motivate shifts in usage which are the most beneficial to the system.

3.4.1. SCE Rebuttal to ORA and SEIA

SCE answers that both the ORA and SEIA proposals inappropriately include relatively low-price hours (2 to 4 p.m. and 3 to 4 p.m., respectively), and both inappropriately exclude a relatively high-price hour (8-9 p.m.). SCE notes that its rebuttal testimony demonstrates that for 2024 summer weekdays the 3-4 p.m. hour is only 77 percent as expensive as the average weekday hour, while the 2-3 p.m. hour is even lower (68 percent). Using the same comparison, the 8-9 p.m. hour is 288 percent as expensive as the average weekday hour.[26] For these reasons, SCE believes it has demonstrated that 4 p.m. to 9 p.m. is the correct peak period for SCE's system.

SCE also disagrees with SEIA's and ORA's advocacy for more moderate proposals based on their analyses using 2021 data. SCE emphasizes that the stability of TOU periods over a sufficient length of time is important because TOU periods form the basis by which customers make long-term investment choices, without being subject to "constantly-changing and confusing price signals": "in a constantly evolving environment, a moderate shift only increases the likelihood for another change in the near future, which may, in turn, have a detrimental impact on customers' investment decisions."[27] SCE asserts that the more appropriate way to moderate the impact of new TOU periods—once they are established—is through rate design implementation in SCE's 2018 GRC Phase 2 proceeding.

3.4.2. Other Parties' Positions

CLECA supports SCE's proposed TOU periods, as "they reflect SCE-specific marginal costs. They also reflect a reasonable effort to create a result that will be straightforward and fairly simple for customers to remember, [by] lining up TOU periods in both summer and winter."[28] As such, CLECA believes they also are understandable and should enable customers to respond by shifting their loads.

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[26] Exhibit SCE-03 at 5, Table II-1.

[27] *Id.* at 9-10.

[28] CLECA Opening Brief at 11, citing Exhibit SCE-01 at 69-73.

CMTA supports SCE's proposed TOU periods because they are cost-based, statistically supportable and based on sound judgment. In particular, CMTA agrees with SCE's recommendation that there be no more than three TOU periods in a season and that a 4 p.m. to 9 p.m. summer peak and 4 p.m. to 9 p.m. winter mid-peak period be adopted for all months of the year. CMTA agrees with SCE that the hour of 3 p.m. to 4 p.m. should not be included in the peak period "[b]ecause this hour 'typically represents the beginning of the ramp' in the afternoon [and] SCE concluded that including it in the period from 9 a.m. to 3 p.m. would provide a price-signal to encourage usage, which would help increase load and flatten the start of the ramp."[29]

Regarding SEIA's proposed TOU periods, CMTA responds "there should be no debate that for grid operations and reliability purposes, sending the correct price signals in order to flatten the duck curve is imperative. For this reason, SEIA's proposal to start the peak period at 2 p.m. should be rejected, since SEIA's proposal would inaccurately signal customers to reduce loads during the start of the ramp period, thereby exacerbating rather than reducing the continually growing duck curve problem."[30]

Our review of the record shows that SCE's analysis fully supports its proposed TOU periods, and they should be adopted. We determined above that SCE's use of a 2024 forecast was reasonable; we also found that SCE's resulting marginal cost estimates were methodologically sound. As such, our reliance upon the extension of those results into determination of new base TOU periods

[29] Exhibit CLECA/CMTA-01, Q&A 25, citing Exhibit SCE-01 at 64.

[30] CMTA Opening Brief at 4.

is reasonable and well-supported by SCE's testimony. The adopted TOU periods are shown below in Table 3-A (weekdays) and Table 3-B (weekends).

Table 3-A
Adopted TOU Periods (Weekdays)

TOU Period	Summer (June – September)	Winter (October – May)
On-peak	4 p.m. - 9 p.m.	
Mid Peak		4 p.m. - 9 p.m.
Off-peak	All hours except 4 p.m. - 9 p.m.	9 p.m.- 8 a.m.
Super-off-peak		8 am - 4 p.m.

Table 3-B
Adopted TOU Periods (Weekends)

TOU Period	Summer (June – September)	Winter (October – May)
On-peak		
Mid Peak	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	All hours except 4 p.m. - 9 p.m.	9 p.m.- 8 a.m.
Super-off-peak		8 am - 4 p.m.

3.5. TOU Period Grandfathering

D.17-01-006 established the qualifying attributes of customers who are entitled to remain on existing TOU periods during a five or ten-year transition depending on the customer type. As described in Ordering Paragraph 5 of D.17-01-006, for non-residential systems, this transition continues for ten years after issuance of a permission to operate, but in no event shall the duration continue beyond December 31, 2027 (for schools) or July 31, 2027 (for all other non-residential). Ordering Paragraph 5 of D.17-01-006 is binding on this proceeding and we do not revisit the TOU grandfathering duration adopted therein.

3.6. Other Mitigation Measures

In D.17-01-006 the Commission specified that new TOU periods should be introduced in a manner that reduces or mitigates negative impacts on customers. The Commission ordered the utilities to ensure that customers with existing behind-the-meter solar be permitted to maintain their existing TOU rate periods for five years (residential customers) or ten years (non-residential customers).[31] The Commission also permitted the utilities to structure an alternative but equivalent mitigation measure for these customers, subject to approval by the Commission.[32]

Several water agencies and water districts intervened in this proceeding in order to request grandfathering or another mitigation measure responsive to their particular circumstances.[33] All the REWDs have a number of renewable energy generation projects, which are either Net Energy Metered (NEM) or participating in the Renewable Energy Self-Service Bill Credit Transfer program (RES-BCT). The REWDs seek relief in this proceeding due to the anticipated effects of SEC's proposed TOU periods on RES-BCT.

The RES-BCT program was established by the legislature effective January 1, 2009, and is codified in Section 2830 of the Public Utilities Code.

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[31] D.17-01-006, Ordering Paragraph 5.

[32] *Ibid.*

[33] These parties are Castaic Lake Water Agency, Eastern Municipal Water District, and Rancho California Water District (hereinafter Renewable Energy Water Districts, or REWDs).

Assembly Bill 512, signed into law in 2011 and effective on January 1, 2012, further modified the program to increase the generator size limit to 5 MW per generation account. The RES-BCT program allows governmental entities, who may not have electric loads where the potential for renewable generation exists, to nevertheless install renewable energy generation projects in those locations. The program allows local governments to generate energy from an eligible renewable generating facility for its own use ("generating account") and to export energy not consumed by the generating account to the electrical grid. Any energy exported by the renewable generating facility to the grid is calculated into bill credits and applied monthly to the designated benefiting account(s). The value of the credit for the exports to the grid from the renewable generator (generating account) is established using only the generation component of the TOU energy charge of the generator account rate schedule. This differs from the NEM tariff, which provides project owners a credit equal to the entire retail rate. Thus, RES-BCT generation credits are heavily dependent on the peak hour pricing structure of SCE's TOU periods.[34]

This structure of the RES-BCT credit mechanism has the result that, if SCE's proposed TOU period changes are adopted, the REWDs will experience a "breathtaking" loss in the value of the solar energy produced by their projects.[35] For this reason, the REWDs request that the Commission allow solar RES-BCT projects to remain on current TOU periods for 20 years from their PTO (Permission to Operate) date. Alternatively, the REWDs request that the

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[34] Exhibit CLWA-01 at 2.

[35] REWD Opening Brief at 3. *See also*, Exhibit RCWD-01 at 2, citing losses of $280,000 per year and Exhibit CLWA-01 at 2, citing losses of $350,000 per year.

Commission establish a "fixed indifference payment protocol" that would be available to behind-the-meter solar projects at the customer's discretion. The protocol would provide an indifference payment of the net present value of the financial impact of TOU period changes for the duration of the grandfathering period.

SCE argues that requests for additional grandfathering must be made through petitions for modification (PFM) of D.17-01-006, not in this utility-specific RDW. SCE also asserts that the other mitigation measures proposed by the Water Districts are contrary to the spirit of the August 9, 2017 ALJ Ruling on Motions to Strike, which held that testimony should be "stricken if the testimony proposes specific rate design changes or other 'mitigation' measures, so that those proposals could be considered with all other rate design proposals in SCE's GRC Phase 2 application, A.17-06-030." For example, SCE and the Agricultural Parties stipulated earlier in this proceeding that the Agricultural Parties' mitigation concerns will be addressed in SCE's pending 2018 GRC Phase 2 proceeding.

EUF argues that providing mitigation beyond already-adopted TOU period grandfathering would be unfair to other customers. EUF suggests that the water districts have not justified that they deserve additional compensation, because if a change to TOU periods was not anticipated, RWCD and REWD did not use all available information, relied on an expert who did not have timely awareness of the duck curve, relied on vendor financial estimates, and have not exhausted other avenues of relief.[36]

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[36] EUF Opening Brief at 9-12. EUF makes unsupported assertions that vendors are "not necessarily neutral, can ignore potential risks and can be optimistic" and states that "this

Footnote continued on next page

3.6.1. Discussion

When passed in 2008, the intent of AB 2466 was "to allow local government entities to credit energy produced from renewable resources owned by the local entity against their electricity usage on more than just the facility where the renewable generator is located."[37] Section 2830 (f) required SCE to file an advice letter that complied with Section 2830, "proposing a rate tariff for a benefiting account" and required this Commission to approve the proposed tariff, or specify conforming changes to be made and filed in a new advice letter.

Evidence in this proceeding demonstrates that if we simply approve SCE's new TOU periods and take no further mitigating actions, we will have contravened the intent of the Legislature by effectively shutting down the program that we were directed to create when the Governor signed AB 2466. SCE and EUF, by opposing some form of relief for the Renewable Energy Water Districts ignore this simple reality of California law. SCE also misreads D.17-01-006 if it believes that decision precluded customers on its RES-BCT tariff from receiving mitigation beyond the Ten-year grandfathering period provided by Ordering Paragraph 5 of that decision. As we made clear earlier in D.17-01-006, "although today's decision adopts grandfathering for a specific situation, <u>we expect that going forward</u> the IOUs, customers, and DER technology providers will develop mitigation measures that are more transparent and more narrowly tailored than grandfathering."[38] To be consistent

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calls into question the diligence used in investigating the projects." We found the REWD witnesses to be entirely credible, and we give no weight here to EUF's unsupported statements.

[37] *See*, e.g., Senate Energy, Utilities And Communications Bill Analysis, June 18, 2008 and Assembly Floor Analysis, August 14, 2008.

[38] D.17-01-006 at 48.

with D.17-01-006 and in order to continue to comply with the legislative intent behind Section 2830, in today's decision we direct that SCE and the Renewable Energy Water Districts work collaboratively in SCE's currently-open GRC Phase 2 proceeding (A.17-06-030) to develop an indifference mechanism that, by mutual agreement, will have the result that the RES-BCT program continues to be a viable mechanism for the governmental entities that entered the program in good faith that it would not be effectively canceled part-way through the life of the investments they made to participate in California's efforts to reduce greenhouse gas emissions and help achieve the state's climate goals.[39]

3.7. Implementation of Adopted TOU Periods

In rebuttal testimony, SCE responded to various parties' concerns about a "dual" implementation of its new TOU periods in October, 2018 followed shortly thereafter by new GRC Phase 2 rates. In response to that concern, SCE proposed a single February 2019 implementation date for both proceedings.

We adopt parties' preferred implementation date of February 2019.

4. Critical Peak Pricing (CPP)

As SCE notes in its application, the highest system marginal costs are often concentrated in a few hours throughout any given year and are driven by high temperature conditions, which generally occur during the summer. To more accurately assign these energy and capacity costs to the few days and hours in each year with highest system load conditions, the Commission has established dynamic pricing rates, such as the CPP and RTP programs.[40]

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[39] Exhibit RCWD-01 at 2-4 and Exhibit CLWA-01 at 3

[40] SCE Application at 9.

SCE made a number of CPP-related proposals in this proceeding:

- Redefine its CPP event periods to align with its proposed TOU periods;
- Redesign certain CPP program elements; and
- Implement default CPP for eligible TOU-GS-1, TOU-GS-2, and TOU-PA-3 customers.

In addition, "based on recent developments and information concerning the cost and efficacy of default CPP" SCE made an alternative proposal that requests optional (as opposed to default) CPP for its small commercial customers.[41]

SCE proposes that these changes take effect on the same date as the rest of this decision in order to align with the adopted TOU periods and to allow customers to adjust to the new rate structures before CPP events are called the following summer.

SCE's alternative proposal provides that SCE would continue to provide opt-in enrollment for TOU-GS-1 customers in the revised CPP program, while maintaining the required transition for TOU-GS-2 and TOU-PA-3 customers to default CPP. SCE asserts that the alternative treatment for TOU-GS-1 customers is reasonable because "the Commission's prior decisions did not take into account newer evidence that demonstrates commercial and industrial (C&I) customers with demands of less than 20 kW who were defaulted to CPP do not meaningfully contribute to load reductions in the on-peak period."[42] SCE asserts that, given the effort and administrative costs involved with defaulting TOU-GS-1 customers, and the "high likelihood" that they will not meaningfully

[41] *Ibid.*

[42] Exhibit SCE-01 at 103.

contribute to the Commission's load impact objectives, the Commission should focus on other, more effective, means to encourage these customers to reduce load.

No party opposed these proposals, but pursuant to the joint stipulation between SCE, Farm Bureau and AECA, SCE supports extending its alternative proposal (*i.e.*, CPP being offered as an optional rather than a default rate) to TOU- PA-3 customers as well. SCE asserts this is reasonable given the unique characteristics of agricultural customers and the relatively small amount of load served under the TOU-PA-3 rate schedules.

We find that we should approve SCE's proposed changes to its CPP rates. However, we deny without prejudice SCE's alternative proposal to offer CPP as an optional rather than a default rate to customers on its TOU-GS-1 and TOU-PA-3 rate schedules. First, SCE seeks to modify the requirements of D.16-03-030, and we decline to do so based on the record before us. Because SCE relies on results in PG&E's territory, our record would have benefitted from more analysis and explanation around the question of why PG&E experienced the results it reported, and why those results should inform our decision on SCE's request. SCE also suggests that it would be costly to implement default CPP for the affected customer groups, but provides little supporting analysis. As such, procedurally, if SCE wishes to pursue its request further the proper route is a petition for modification of D.16-03-030. This would allow the Commission to re-consider SCE's alternative CPP proposal prior to the implementation date for the instant decision.

The CPP changes authorized in this decision shall be implemented on the same date as other proposals in this decision, February 1, 2019.

5. Real-Time Pricing (RTP)

As SCE notes in its application RTP tariffs provide customers with more accurate and granular energy price information, allowing customers to tailor energy usage and save on energy bills by more precisely avoiding high-cost period usage and conversely, increasing usage during low-cost periods. SCE requests authority to simplify and revise its RTP tariffs in order to better align the price profiles of those rates to actual costs, and to encourage greater customer participation.

In testimony, SCE explains that its current RTP schedules offer menus of hourly prices to non-residential customers that reflect hourly marginal energy and capacity costs, aggregated into nine seasonal 24-hour price sets, which differ based on season, day type (workday versus weekend), and temperature. This structure was first implemented in 1988, and has remained largely unchanged. SCE states that because its RTP pricing structure provides strong cost signals to customers and encourages demand response, SCE's RTP customers have provided significant load reductions during system peak hours.

SCE also explains how its proposals in this proceeding will affect its RTP pricing structure. First, temperature will continue to be the trigger for RTP date types, because temperature remains highly correlated with SCE's system peak demands. Second, implementation of forecast 2024 marginal generation costs would result in RTP rates with high cost hours shifted to later in the day and concentrated in "far fewer" hours. Third, introduction of the 2024 marginal generation costs also changes the shape of the RTP rates from a "bell curved" price shape to a "duck curve." In addition, introduction of flexible capacity results in an allocation of generation capacity costs to every RTP day type, unlike the current RTP rates which do not allocate any generation capacity costs to winter or weekend days.

Given the above impacts on SCE's current RTP schedules, SCE proposes to simplify the RTP rate structure and (possibly) increase program enrollment by condensing the current five-tier summer weekday prices into three day-types. Thus, summer weekday types would consist of three price tiers for: (1) temperatures below 80 degrees, (2) between 81 – 90 degrees, and (3) above 90 degrees.

SCE explains that reducing the number of summer day types results in a reduction of the summer hottest day's peak price from $9.30/kWh to $3.80/kWh, which is much closer to today's peak price of $2.50/kWh. SCE acknowledges that "while the current distribution of day types provides greater price granularity, prices in the highest temperature day have often proved to be a barrier when marketing to customers. Therefore, softening the peak prices is a reasonable compromise between precision and customer acceptance."

SCE also provides bill impact analyses for its proposed changes, which we summarize below:

- 75% of current RTP customers will not be significantly impacted by the changes (i.e., a bill impact between -5% and 5%);
- 13% of current RTP customers already have usage patterns that align well with the 2024 price profile, and will see a bill reduction; and
- 12% of current RTP customers will be negatively impacted by the proposed changes.

Regarding the negatively impacted group, SCE notes that these customers have historically been very responsive to RTP price signals, such that although their current usage patterns have been optimized to respond to current RTP price profiles, these bill impacts do not account for customer's [likely] responses to the new price profiles and do not reflect the expected actual bill after the new RTP rates are implemented. In short, SCE expects that this third group of customers will actively shift load in response to anew 2024 RTP price profile.

No party opposed SCE's RTP proposals.

We find that SCE's proposed changes to its RTP rate design are well supported by the evidence and SCE's analysis, and we authorize the proposed changes. These authorized changes shall be implemented on the same date as other proposals in this decision, February 1, 2019.

6. Marketing, Education, and Outreach (ME&O)

SCE proposed a ME&O campaign for its new TOU period roll-out in direct testimony. While that proposal was challenged in part by SBUA, those differences were resolved through the joint stipulation between SCE and SBUA. With the clarifications and additions provided for in that stipulation, SCE requests that its ME&O plan be approved in its entirety.

We approve SCE's proposed ME&O campaign for its new TOU period roll-out, with the clarifications and additions provided for in the stipulation the joint stipulation between SCE and SBUA.

7. Distributed Energy Resources (DER) Action Plan

On November 10, 2016 the Commission endorsed a "Distributed Energy Resources Action Plan" (DER Action Plan). Distributed energy resources are defined as distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. The purpose of the DER Action Plan is to continue the Commission's support of DER, accomplishing four objectives:

1. Provide a long-term vision for DER and supporting policies;
2. Identify continuing efforts in support of the long-term vision;
3. Assess and direct further near-term action needed to support long-term vision; and
4. Establish a DER coordinating committee responsible for sustained coordination of DER activities.

To accomplish this purpose, the DER Action Plan endorses a strategic scope and structure, including three groups of related proceedings or initiatives:

1. Rates and Tariffs;
2. Distribution Grid Infrastructure, Planning, Interconnection and Procurement; and
3. Wholesale DER Market Integration and Interconnection.

The DER Action Plan includes vision, continuing, and action elements for each proceeding grouping.[43]

Within the Rates and Tariffs group, five vision elements are identified:

A. A continuum of rate options, from the simple to complex, is available for customers, and customers are educated to make informed choices;

B. Rates reflect time-varying marginal cost;

C. Processes for adopting innovative rates and tariffs are flexible and timely;

D. Rates and demand charges better reflect cost causation and capacity benefits of DERs; and

E. Rates remain affordable for non-DER customers.

[43] The "continuing" elements are ongoing efforts that help achieve the vision. "Action" elements are additional efforts considered necessary for achieving the vision.

The DER Action Plan states that the Commission is actively considering augmentations and refinements to many DER policies in Commission proceedings. Specifically, the DER Action Plan identifies "consideration of fixed charges, TOU periods and rates, nonresidential rate design, including enhancements to dynamic rates" as a "continuing" element in Rate Design Window and GRC Phase 2 proceedings, as well as "appropriate rate designs to absorb renewables oversupply."

The Scoping Memo for this proceeding determined that in order to provide information necessary to help the Commission align its vision and actions to shape California's distributed energy resources future, the record in this proceeding should be supplemented to include input from SCE and other parties regarding how SCE's application addresses any or all of the vision and continuing elements identified within the Rates and Tariffs group of the DER Action Plan. SCE was directed to serve responsive testimony, and intervenors could then address SCE's testimony in their rebuttal and reply testimony.

SCE asserts that its supplemental testimony (Exhibit SCE-02) demonstrated how SCE's proposals in this proceeding meet the applicable "vision" and "continuing" elements of the DER Action Plan. For example, SCE demonstrated that its TOU proposals reflect the time-variation of marginal costs and that, overall, sending customers economically-efficient price signals "will help compensate DER customers fairly while helping to maintain non-DER customer affordability."[44] SCE testified that its new proposed TOU periods would encourage certain kinds of DER adoption, namely energy storage.[45] SCE

[44] Exhibit SCE-02 at 9.

[45] RT at 92-93.

also placed the DER Action Plan into the Commission's overall policymaking context by noting that specific rate designs and potential mitigation measures as they relate to DERs as a result of the new TOU periods adopted in this proceeding have either already been decided in D.17-01-006 or will be decided in SCE's pending 2018 GRC Phase 2 proceeding, A.17-06-030.

We acknowledge the effort made by SCE to demonstrate how SCE's application addresses the vision and continuing elements identified within the Rates and Tariffs group of the DER Action Plan. SCE's explanation of how DER-related rate designs and potential mitigation measures resulting from the TOU periods adopted in this proceeding are interrelated with other proceedings is invaluable information that we will rely upon to coordinate the outcomes of the various proceedings that affect DER, either directly or indirectly.

8. Option R Cap

SCE's Option R rate schedules are available to commercial and industrial customers with demands greater than 20 kilowatts (kWs) but not exceeding four megawatts (MW) and employ Renewable Distributed Generation Technologies.[46] Option R rates feature reduced demand charges and correspondingly higher volumetric TOU rates, a rate structure that is attractive to solar customers. The Commission first adopted Option R in D.09-08-028, which approved a settlement resolving SCE's 2009 GRC Phase 2 proceeding. As part of the settlement, subscription on Option R was limited to a cumulative installed distributed generation output capacity of 150 MW for all eligible rate groups.

[46] This term is defined as solar, wind, fuel cells, and any other renewable generation technology as defined in the Statewide California Solar Initiative, the Self-Generation Incentive Program, or their successors.

The settlement in SCE's 2013 rate design window increased the level of this cap to 400 MW, and provided that the cap shall remain at that level until "the date on which SCE's tariffs implementing its 2018 GRC Phase 2 are effective."[47]

CALSEIA requested that this RDW proceeding consider raising the Option R cap in advance of SCE's Phase 2 proceeding because "it is now apparent [to CALSEIA] that the 400 MW cap will likely be exhausted before the conclusion of the 2018 GRC."[48] After considering the issue, the Scoping Memo did include this issue in the scope of this proceeding, because good cause existed for doing so: (1) CALSEIA was not a party to the 2013 RDW settlement, but its members are directly impacted by the cap agreed upon in that settlement; (2) CALSEIA presented a reasonable argument that (i) the cap could be reached sooner than it can be addressed in SCE's 2018 GRC Phase 2, and (ii) reaching that cap will present real-world difficulties to SCE customers who are interested in taking service under Option R rates; and (3) the Commission would not be disturbing the give-and-take of the 2013 RDW settlement simply by taking up the issue sooner than anticipated by the settlement.

Since the Scoping Memo was issued in March 2017, we have more record evidence on progress toward meeting the cap, and SCE filed its 2018 GRC Phase 2 application on June 1, 2017 (A.17-06-030). We take notice of the fact that SCE's testimony in that proceeding includes a proposal to replace Option R (we also take notice of the fact that some parties in that proceeding support

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[47] A.13-12-015, "Settlement Agreement Resolving Southern California Edison Company's 12013 Rate Design Window Application" Section 4.c., "Rate R Megawatt Cap." CALSEIA was not a party to the Settlement Agreement.

[48] While this proceeding has been pending, CALSEIA changed its name to California Solar & Storage Association (CALSSA).

SCE's proposal, while other parties served testimony in opposition to the proposal). The Scoping Memo in that proceeding anticipates a Commission decision on SCE's application in December 2018. Thus, it remains reasonable to address the Option R cap here in order to avoid the uncertainty inherent in simply deferring the matter to A.17-06-030.

SCE opposes raising the cap in this proceeding on policy grounds and because it believes it demonstrated that it is unlikely that the Option R cap will be reached before the implementation of new GRC Phase 2 rates in early 2019, so there is no need for the Commission to reach a determination of the issue here.[49]

EUF argues that this RDW is not the proper forum for changing the cap, asserting that there are open questions regarding the cost shift associated with Option R, which are properly addressed in the SCE's GRC Phase 2. Until that issue is fully evaluated, EUF believes it is premature to determine whether the Option R cap should be increased, and if so, by how much.

Our main concern at this time remains whether the Option R cap will be reached before the Commission's decision in A.17-06-030 addresses the future of Option R. In testimony, CALSEIA noted SCE's website reported that as of April 2017, 124.7 MW of "headroom" remained under the cap, and stated that the cap could be reached by April 2018 or sooner.[50] In rebuttal testimony, SCE provided calculations that suggested otherwise. SCE cited participation levels since 2015 that showed approximately 13 MW of new installed capacity takes

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[49] *Se*e Exhibit SCE-03, pp. 67-68; *see also* SCE, Thomas, Evidentiary Hearing Tr. 1: 18; Exhibit SCE-104 at 6 (CALSEIA *ex parte* communication showing its estimate of trends for commercial NEM interconnections).

[50] Exhibit CALSEIA-01 at 14.

service on Option R each quarter.[51] At that rate, SCE estimated that it would take roughly 27 months to reach the existing 400 MW cap, or August 2019 (SCE served its rebuttal testimony in June, 2017).

With the passage of time, more recent data have shown both CALSEIA and SCE to be off the mark. First, as noted above, in April, 2017 124.7 MW remained available under the cap. Second, in June, 2017 100.12 MW remained available.[52] Third, we take official notice of the most recent report on SCE's website, which shows that as of May 7, 2018 40.93 MW remained available.[53] Thus, the cap has not been reached, as CALSEIA predicted[54] nor is capacity likely to remain available until August 2019, as SCE predicted. Nevertheless, we calculate that in the 10 ½ months between the June 2017 and May 2018 reports, available MW reduced by 59.2 MW, or 5.5 MW per month. At that rate, the 400 MW Option R cap would be reached in December, 2018: the date the Commission expects to act on the proposals in A.17-06-030 (if this schedule holds, the ALJ's proposed decision will have issued in November, 2018). Thus, it no longer appears likely that the capacity available under the current Option R will be <u>materially</u> exhausted before the conclusion of SCE's GRC Phase 2 proceeding.

8.1. Discussion

We find that we should neither raise nor remove the Option R cap in this proceeding. Our finding is based on the evidentiary record in this proceeding, as

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[51] Exhibit SCE-03 at 67 and Figure IX-26.

[52] Exhibit CALSEIA-100, again providing the then-current report from SCE's website.

[53] SCE's April 3, 2018 report is attached to this decision as Appendix 3.

[54] Exhibit CALSEIA-01 at 17, Q and A at lines 4-8.

well as our taking official notice of SCE's more recent Option R data, and procedural developments since the Scoping Memo was issued.

First, in D.17-01-006 we established the framework for a limited grandfathering measure for existing solar customers. That framework included eligibility criteria to enable customers who were in the process of installing a solar facility to be eligible for grandfathering of the TOU periods that were in place at the time they made their investment decision. In D.17-10-018, the Commission modified D.17-01-006 to provide eligibility for systems for which "Public Agencies" (including "public water and/or sanitation agencies") filed an initial interconnection application no later than 60 days following the issuance of D.17-10-018.[55] In D.17-01-006 we also acknowledged that there will still be customers in the process of contracting for or installing solar facilities that do not qualify for the grace period deadlines.[56] Thus, solar interests have known of the grandfathering rules that affect them since January, 2017. We have no record in this proceeding that would explain to us why a new solar customer would sign up now for Option R when they do not qualify to be "grandfathered" and retain the current Option R TOU periods.

Second, as SCE notes in its reply brief, in A.17-06-030 SCE has proposed to replace Option R with a new "Option E", which SCE describes as "similar in that it would recover generation and a portion of distribution capacity costs through energy charges, but it is based on the updated TOU periods proposed by SCE in this proceeding."[57] We do take notice of the fact that CALSEIA opposes SCE's

[55] D.17-10-018, Ordering Paragraph 1.

[56] D.17-01-006 at 63.

[57] SCE Reply Brief at 11.

proposal in testimony served on March 23, 2018. We also wish to avoid creating a situation where, by lifting the cap, an inordinate number of new customers (*i.e.*, at a rate above historical trends) sign up for Option R in the next six months. SCE's witness discussed this "gold rush" phenomenon during hearings when explaining his disagreements with CALSEIA's calculations:[58]

> Mr. Thomas: Well, let me qualify the data. I just received it this morning. I was able to do a very quick review. I can say that the data looks at a very short period, so, therefore, the regression is essentially looking at the tip, or the end of regression, which would accelerate what you would see.
>
> What's included in this data, right, is the gold rush, or the rush of applications that preceded the TOU OIR final decision. So, therefore, that would steepen the slope.

We face a similar situation here, now that SCE has proposed a replacement for Option R in A.17-06-030: once prospective customers could see what a prospective alternative to the current Option R might look like (*i.e.*, different TOU periods) they rushed to sign up for the current version. Here, prospective customers now know what SCE has proposed, and the Commission is considering, in SCE's Phase 2 proceeding. We do not wish to encourage or create unlimited opportunities for new solar customers to take service on the current Option R while we consider its replacement in another proceeding before us.

Indeed, due to developments in the past year, CALSEIA's testimony has the unintended effect of reinforcing our conclusions. CALSEIA discusses the impact of uncertainty about Option R on non-residential solar projects:

> The average timeframe to complete solar projects is about one year, which means that projects that are starting development

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[58] RT at 16-17.

> now [*i.e.*, late April, 2017] would likely have to assume that Option R will not be available when the project comes online. Thus, diligent solar developers are likely already informing potential customers that Option R might not be available when their systems become operational. This means that when customers perform their own due diligence, they would assume that Option R would not be available to them. Customers utilizing less solar friendly rates (*i.e.*, no Option R rates) in their analyses would yield less economically favorable results, making them far less likely to pursue these solar projects at all.[59]

Based on the above, we would create more uncertainty, not less, if we changed the level of the Option R cap at this time. Regardless of whether the Commission ultimately approves SCE's newly proposed Option E, since we will soon be determining the future of Option R in A.17-06-030, we see little sense in raising the cap now and prefer to take what we now see as a small risk that the 400 MW cap will be reached before that date.

9. Comments on Proposed Decision

The proposed decision of the assigned ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ___________ by ___________. Reply comments were filed on ___________ by ___________.

10. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Stephen C. Roscow is the assigned ALJ in this proceeding.

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[59] *Exhibit CALSEIA-01* at 17-18, emphasis added.

Findings of Fact

1. Although not binding on this proceeding, D.17-01-006 describes the principles we should adhere to when considering whether to change the current TOU periods.

2. In D.17-01-006, the Commission defined "base TOU periods" as those TOU time periods during which customers, generators, and providers of energy services should be encouraged to modify electric usage and supply.

3. In D.17-01-006, the Commission determined that base TOU periods should be developed using utility-specific, forward-looking data, with the forecast year set at least three years after the base TOU periods will go into effect.

4. Public Utilities Code Section 745(c)(3) directs the Commission to "strive" for residential TOU periods that are appropriate for at least the following five years.

5. SCE demonstrated that the differences in the results of its marginal cost studies for 2021 and 2024 with regard to determining TOU periods are not significant.

6. Absent a settlement, the Commission adopts values for marginal costs that are calculated using specific inputs.

7. SCE's proposed 2024 marginal energy costs are uncontested.

8. SCE's methodology for determining distribution marginal costs reasonably accounted for future DG penetration.

9. In D.17-01-006, the Commission determined that the use of marginal distribution and transmission cost information in setting future base TOU periods will be addressed in individual IOU rate proceedings.

10. SCE's rebuttal testimony shows that summer weekday and weekend costs vary dramatically.

11. SCE's data supports retaining the current definition of SCE's summer season, June-September.

12. Evidence based on SCE's 2024 forecast and the resulting marginal cost estimates supports SCE's proposed TOU periods.

13. In D.17-01-006, the Commission specified that new TOU periods should be introduced in a manner that reduces or mitigates negative impacts on customers.

14. In D.17-01-006, the Commission established the qualifying attributes of customers with existing behind-the-meter solar who are entitled to remain on existing TOU periods during a five or ten-year transition depending on the customer type.

15. In D.17-01-006, the Commission permitted the utilities to structure an alternative but equivalent mitigation measure for customers with existing behind-the-meter solar, subject to approval by the Commission.

16. The Renewable Energy Self-Service Bill Credit Transfer program (RES-BCT) program was established by the legislature effective January 1, 2009, and is codified in Section 2830 of the Public Utilities Code. Assembly Bill 512, signed into law in 2011 and effective on January 1, 2012, further modified the program to increase the generator size limit to 5 MW per generation account.

17. The RES-BCT program allows governmental entities, who may not have electric loads where the potential for renewable generation exists, to nevertheless install renewable energy generation projects in those locations.

18. The RES-BCT program credit for the exports to the grid is established using only the generation component of the TOU energy charge of the generator account rate schedule.

19. The Net Energy Metering tariff provides project owners a credit equal to the entire retail rate.

20. RES-BCT generation credits are heavily dependent on the peak hour pricing structure of SCE's TOU periods.

21. Evidence in this proceeding shows that the value of the solar energy produced by the renewable energy water districts' projects will decrease significantly once SCE's proposed TOU period changes take effect unless mitigating actions are taken beyond the grandfathering provisions established in D.17-01-006.

22. The Scoping Memo included the issue of whether the Commission should eliminate the cap on enrollment on SCE's Option R tariffs in the scope of this proceeding because good cause existed for doing so.

23. It no longer appears likely that the capacity available under the current Option R tariff will be materially exhausted before the conclusion of SCE's GRC Phase 2 proceeding.

Conclusions of Law

1. SCE's marginal cost study using reference year data from 2024 should be used in the marginal cost analyses for setting SCE's standard TOU periods.

2. SCE's uncontested 2024 marginal energy costs should be approved for use in this proceeding.

3. SCE's estimate of marginal generation capacity cost of $147.26 per kW-year should be approved for use in this proceeding.

4. SCE's proposed distribution marginal costs should be approved for use in this proceeding.

5. It is not necessary to incorporate marginal transmission costs into SCE's TOU period calculations at this time.

6. SCE's proposal to differentiate between weekdays and weekends for its summertime TOU periods should be adopted because it is supported by the underlying cost data.

7. SCE should retain its four-month summer (June-September) and eight-month winter (October-May) seasons.

8. SCE's proposed TOU periods should be adopted because they are supported by evidence in this proceeding.

9. The grandfathering proposals made by the Castaic Lake Water Agency, Rancho California Water District, and Renewable Energy Water Districts should not be adopted.

10. In D.17-01-006 the Commission adopted TOU rate period grandfathering for a specific situation but stated its expectation that going forward the IOUs, customers, and DER technology providers will develop mitigation measures that are more transparent and more narrowly tailored than grandfathering.

11. Pub. Util. Code Section 2830 (f) requires the Commission to approve a tariff, or specify conforming changes to be made, in order to implement the intent of the Legislature to allow local government entities to credit energy produced from renewable resources owned by the local entity against their electricity usage on more than just the facility where the renewable generator is located in a manner that creates a viable RES-BCT program.

12. SCE and the renewable energy water districts in this proceeding should collaborate in SCE's currently-open GRC Phase 2 proceeding (A.17-06-030) to develop an indifference mechanism that will have the result that the RES-BCT program continues to be a viable mechanism for the governmental entities that participate in the program.

13. The current 400 MW cap on Option R enrollment should not be increased or removed in this proceeding.

14. The rates and tariff modifications approved in this decision should take effect on February 1, 2019.

ORDER

IT IS ORDERED that:

1. The time-of-use periods shown in Appendix 2 to this decision are adopted.

2. Southern California Edison shall implement the specific terms of this decision as one or more Tier 1 Advice Letters no later than 45 days prior to the February 1, 2019 effective date of the rates and tariff modifications approved in this decision.

3. Southern California Edison (SCE) and the renewable energy water districts that are parties in this proceeding are directed to work collaboratively in SCE's currently-open General Rate Case Phase 2 proceeding (Application 17-06-030) to develop an indifference mechanism that, by mutual agreement, will have the result that SCE's Renewable Energy Self-Service Bill Credit Transfer program continues to be a viable mechanism for the governmental entities that participate in the program.

4. Application 16-09-003 is closed.

This order is effective today.

Dated ______________________, 2018, at San Francisco, California.

Appendix 1

D.17-01-006
Policy Guidelines Applicable to the Design, Implementation, and Modification of Time-of-Use (TOU) Periods to be Used in Rate Designs

Appendix 1

Policy Guidelines Applicable to the Design, Implementation, and Modification of Time-of-Use (TOU) Periods to be Used in Rate Designs

1. Base TOU periods and related rate designs should be established independently for each utility either in a general rate case (GRC) or a rate design window (RDW). Geographically-differentiated TOU time periods within an IOU's service territory are not required or encouraged at this time. Any proposals for geographically-differentiated rates must demonstrate that the proposed rates do not conflict with universal and non-discriminatory service requirements.

2. Base TOU periods should be based on utility-specific marginal costs, rather than on a statewide load assessment. This marginal cost analysis should use marginal generation cost, consisting of marginal energy costs and marginal generation capacity costs. Going forward, the IOUs should include information on marginal distribution costs that contribute to peak load costs and time of use information filed or adopted in FERC transmission rate proceedings. Use of marginal distribution and transmission cost information in setting future Base TOU periods will be addressed in individual IOU rate proceedings.

3. As a secondary check on the marginal cost analysis, the IOUs should provide hourly load and net load data and explain any significant differences between estimated high and low marginal cost hours and the net load shapes (including adjusted net load data for PG&E). As part of its TOU period analysis, each IOU should submit the latest data and assumptions, including those vetted in the Long Term Procurement Planning (LTPP) and/or Integrated Resource Planning (IRP) or successor proceeding.

4. Base TOU periods should be developed using forward-looking data, with the forecast year set at least three years after the year the Base TOU period will go into effect.

5. Base TOU periods should continue for a minimum of five years (unless material changes in relevant assumptions indicate the need for more frequent Base TOU period revisions) and each IOU should propose new Base TOU periods, if warranted, at least every two general rate case cycles.

6. Each IOU, in a Tier 3 Advice Letter, should propose a dead band tolerance range for determining when a change would trigger TOU period revisions more frequently than five year intervals. To evaluate whether a dead band tolerance range has been exceeded and to ensure that the Commission and the public are aware of the likelihood of future Base TOU period changes, Base TOU period analysis should be provided in

each general rate case, even if the IOU does not propose a change in Base TOU periods. If such analysis shows that the dead band tolerance range has been exceeded, the IOU should propose revisions to Base TOU periods.

7. Each IOU should take steps to minimize the impact of TOU peak period changes on customers who have invested in on-site renewable generation or technology to conserve energy during peak periods. Regularly scheduled updates to TOU periods will provide predictability for these customers. Additional steps to increase certainty around TOU periods could include vintaging, legacy TOU periods, or fixed indifference payments, as well as other rate structures that provide predetermined limits on TOU period changes. Such steps must also include making information on potential shifts in peak periods available to the public.

8. A menu of TOU rate options should be developed in utility-specific rate design proceedings and should provide rate choices addressing different customer profiles and needs. IOUs are encouraged to use the Base TOU periods to develop at least one optional TOU rate design with a more complex combination of seasons and time periods and may incorporate more dynamic pricing features and enabling technology as appropriate to address grid needs.

9. TOU periods used in rate designs should be designed around the Base TOU periods and should reflect up to date marginal costs, but may be modified to take into account customer acceptance, preferences, understanding, ability to respond and similar factors. These considerations include:

- The extent to which customers understand TOU rates generally.
- The time and education required for customers to transition to a new TOU rate period.
- The ability of customers to respond at a specific time of day or over a given period of time.
- Customers' need for predictable TOU periods, including the schedule of possible TOU rate period changes, when they make investment decisions regarding energy efficiency, storage, photovoltaics, electric vehicles and other distributed energy resources or consider major operational changes to shift usage outside of peak periods.
- The appropriate treatment of different customer classes, as necessary, in light of the fact that customer needs and sophistication may vary by customer class.

(END OF APPENDIX 1)

Appendix 2

A.16-09-003
Southern California Edison
Adopted TOU Periods

Appendix 2

A.16-09-003
Southern California Edison
Adopted TOU Periods

Table 3-A
Adopted TOU Periods (Weekdays)

TOU Period	Summer (June – September)	Winter (October – May)
On-peak	4 p.m. - 9 p.m.	
Mid Peak		4 p.m. - 9 p.m.
Off-peak	All hours except 4 p.m. - 9 p.m.	9 p.m.- 8 a.m.
Super-off-peak		8 am - 4 p.m.

Table 3-B
Adopted TOU Periods (Weekends)

TOU Period	Summer (June – September)	Winter (October – May)
On-peak		
Mid Peak	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	All hours except 4 p.m. - 9 p.m.	9 p.m.- 8 a.m.
Super-off-peak		8 am - 4 p.m.

(End of Appendix 2)

Appendix 3

Southern California Edison Company
Option R Tariff

Approved to Transition to
Option R Tariff (MW)

Option R Tariff Available MW

(as of April 3, 2018)

Appendix 3
Option R Tariff

Effective January 1, 2015, the enrollment cap for Option R of Rate Schedules TOU-GS-2, TOU-GS-3 and TOU-8 was increased from 150 megawatts (MW) to 400 MW. As a result, customers meeting the eligibility requirements for Option R may now have their eligible accounts placed on this rate option after receiving written Permission to Operate (PTO) their Generating Facility from SCE. Customers cannot "reserve" capacity under the Option R enrollment cap prior to receiving PTO.

Customers receiving service under the TOU-8 Option A Special Solar Allowance may request to take service on Option R beginning January 1, 2015, and will not be subject to the 12-month requirement of Rule 12, Section D.2.a provided they transition prior to July 1, 2015.

Interested customers should work with their SCE Account Representative to receive an Option R rate analysis so that they can ascertain how the rate option may impact them. Customers who request to move forward with receiving service on Option R should complete and submit Form CSD-179-A, Request for a Change of Rate Schedule to MCB SPOCs.

Additional Information

To qualify for Option R tariff, your account must meet the following eligibility criteria:

- Account must have annual peak demands greater than 20 kilowatts (kW) but not exceeding 4 MW
- Account must have an approved generating facility interconnected that is powered by solar, wind, fuel cells or other eligible onsite Renewable Distributed Generation Technologies as defined by the CSI or SGIP
- Eligible generating facilities must have a net renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand, as recorded over the previous 12 months
- For customers without 12 months of demand data, SCE will determine the annual peak demand once the customer has three months of demand data
- Account must qualify for service under Rate Schedules TOU-GS-2, TOU-GS-3 or TOU-8
- No other non-renewable generators on site
- Permission to Operate (PTO) letter issued

Option R will be closed to new service accounts when the 400 MW enrollment cap is reached. After the 400 MW cap is reached, service accounts placed on Option R cannot increase the generation system size above what was previously approved. If the generation system size is increased, the account will be removed from Option R. Below is the cumulative total.

Option R Tariff (Date as of May 7, 2018)	
Approved to Transition to Option R Tariff (MW)	**Available MW**
359.07	40.93

This figure is currently updated monthly. The frequency of the updates will increase as the available capacity decreases.

(END OF APPENDIX 3)